

## **Cost Model for CO<sub>2</sub>-Based Enhanced Oil Recovery (CO<sub>2</sub>-EOR)**

This appendix provides documentation for the cost module of the desktop CO<sub>2</sub>-EOR policy and analytical model (COTWO) developed by Advanced Resources for DOE/FE-HQ. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO<sub>2</sub>-EOR project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for New Mexico.

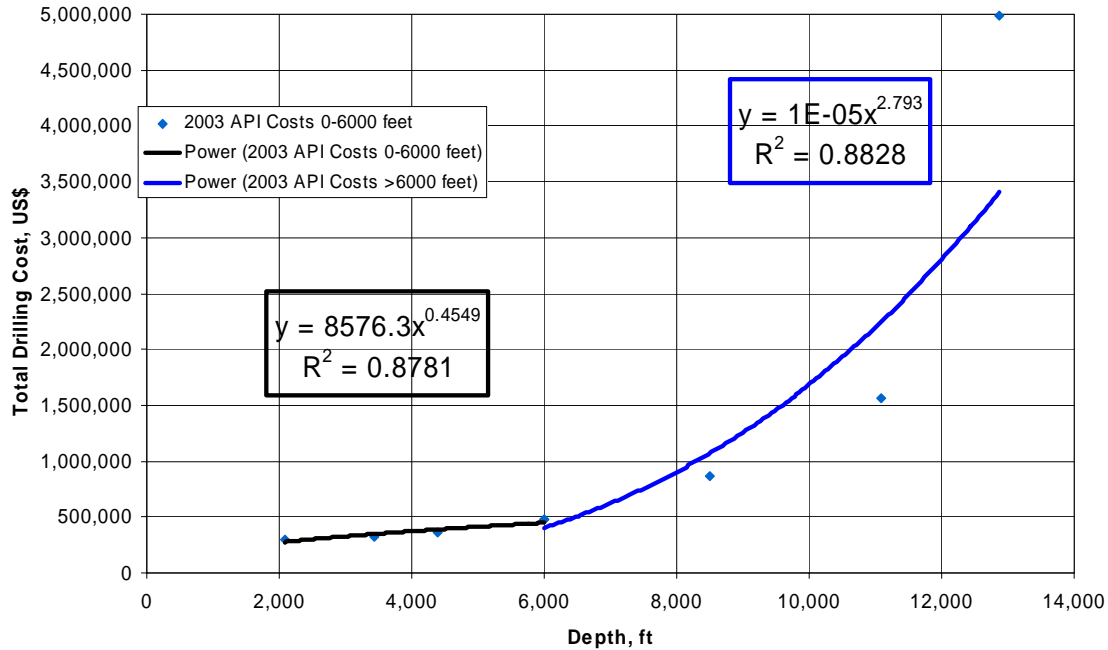
The well D&C cost equation has fixed cost constants for site preparation and other fixed cost items and variable cost equations that increases exponentially with depth for depths 0-6000 feet and greater than 6000 feet. The total equation is:

New Mexico drilling, 0-6000 feet  
Well D&C Costs =  $a_0 D^{a_1}$   
Where:  $a_0$  is 8576  
 $a_1$  is 10.45  
D is well depth

New Mexico drilling, >6000 feet  
Well D&C Costs =  $a_0 D^{a_1}$   
Where:  $a_0$  is  $1 \times 10^{-5}$   
 $a_1$  is 2.79  
D is well depth

Figure C-1 provides the details for the cost equation and illustrates the “goodness of fit” for the well D&C cost equation for New Mexico.

Figure C-1. Oil Well D&C Costs for New Mexico



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

$$\text{Drilling costs (per foot)} = \$5.04(\text{annual oil price}) - \$3.2116.$$

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the New Mexico D&C cost calculations to reflect this increase in 2004 drilling costs.

2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 “Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations” report. This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 12,000 feet, into a central tank battery.

The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

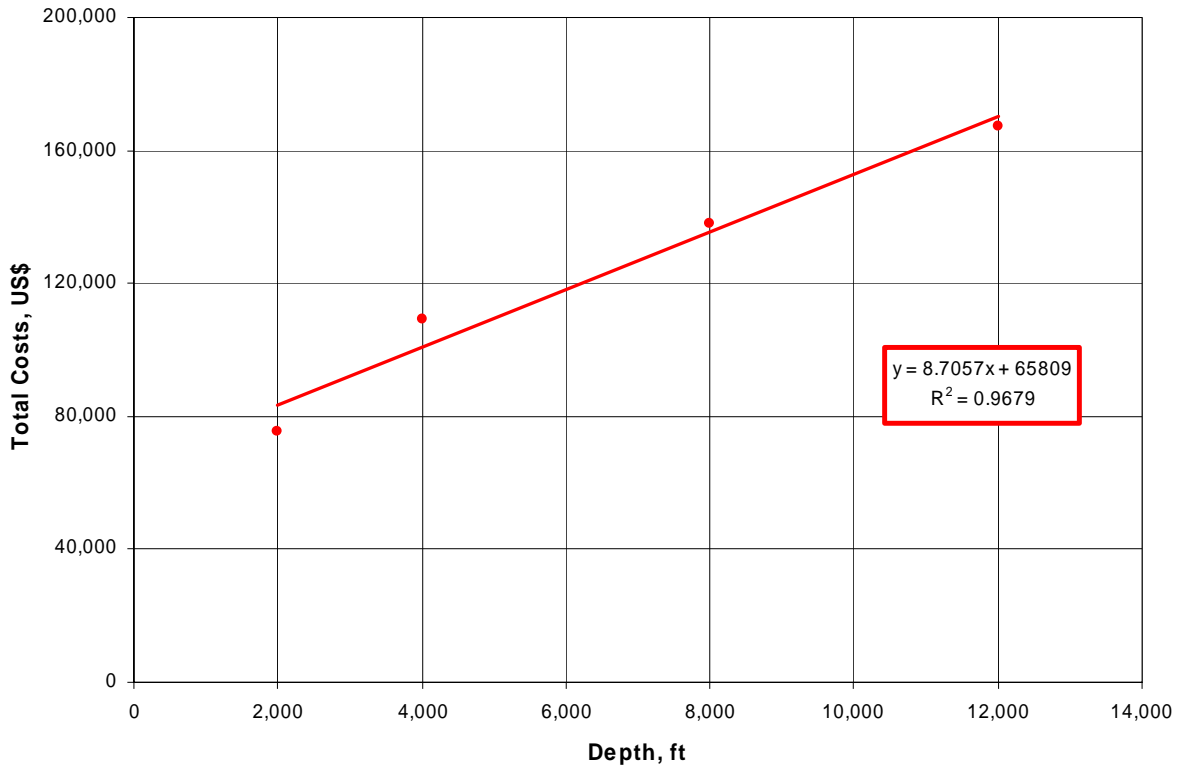
$$\text{Production Well Equipping Costs} = c_0 + c_1D$$

Where:  $c_0 = \$65,809$  (fixed)

$c_1 = \$8.706$  per foot  
D is well depth

Figure C-2 illustrates the application of the lease equipping cost equation for a new oil production well as a function of depth.

Figure C-2. Lease Equipping Cost for a New Oil Production Well in New Mexico vs. Depth



3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in New Mexico include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for New Mexico is:

$$\text{Injection Well Equipping Costs} = c_0 + c_1D$$

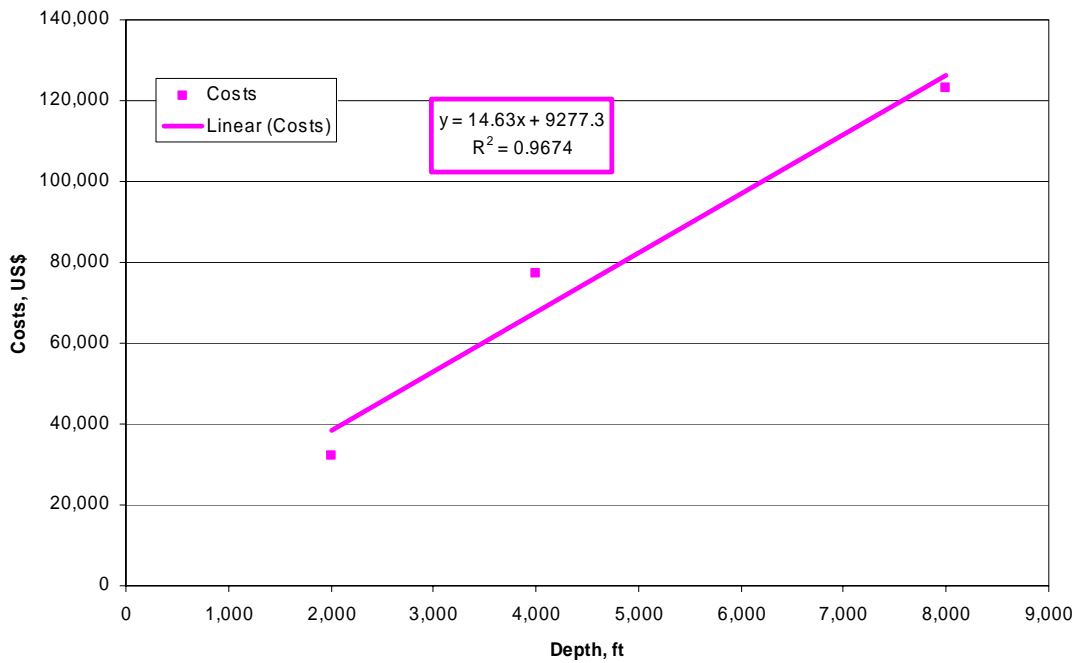
Where:  $c_0 = \$9,277$  (fixed)

$c_1 = \$14.63$  per foot

D is well depth

Figure C-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas. The West Texas cost data for lease equipment provides the foundation for the New Mexico cost equation.

Figure C-3. Lease Equipping Costs for a New Injection Well in West Texas vs. Depth



4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO<sub>2</sub> and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for New Mexico is:

$$\text{Well Conversion Costs} = c_0 + c_1D$$

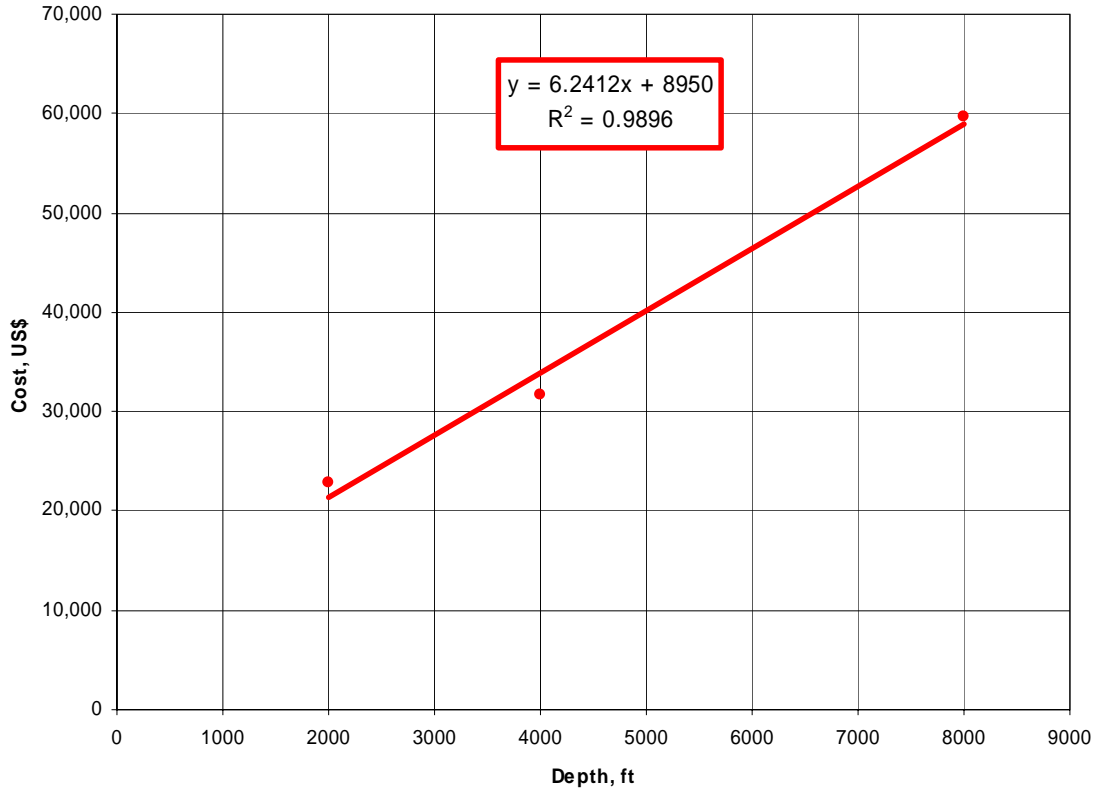
Where:  $c_0 = \$8,950$  (fixed)

$c_1 = \$6.24$  per foot

D is well depth

Figure C-4 illustrates the average cost of converting an existing producer into an injection well for West Texas. The West Texas cost data for converting wells provide the foundation for the New Mexico cost equation.

Figure C-4. Cost of Converting Existing Production Wells into Injection Wells in West Texas vs. Depth



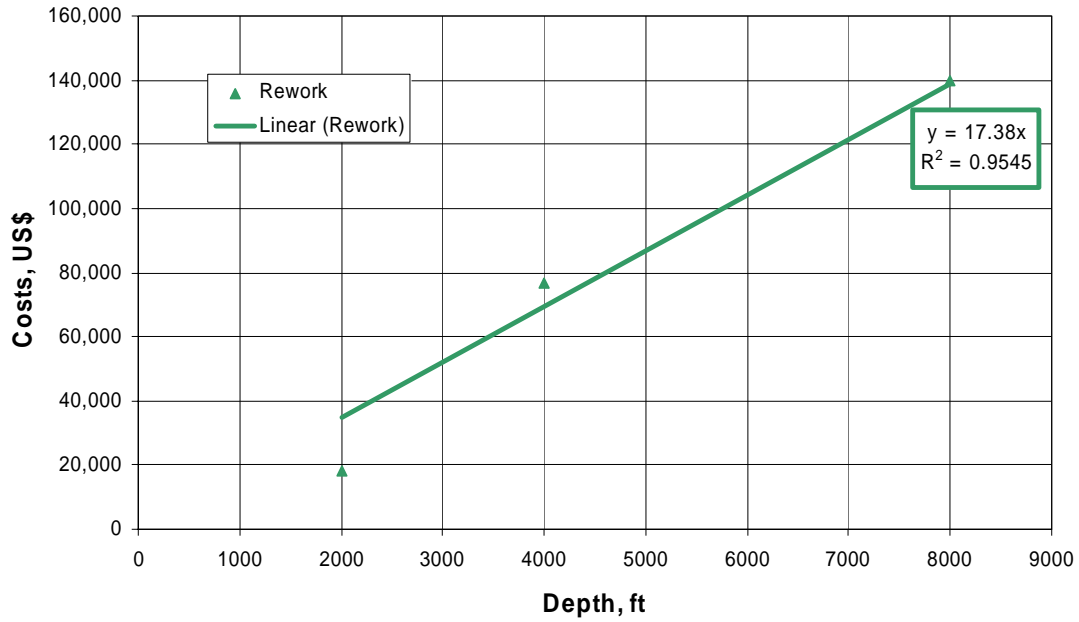
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO<sub>2</sub>-EOR (First Rework). The reworking of existing oil production or CO<sub>2</sub>-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for New Mexico is:

$$\text{Well Rework Costs} = c_1 D$$

Where:  $c_1 = \$17.38$  per foot  
 $D$  is well depth

Figure C-5 illustrates the average cost of well conversion as a function of depth for West Texas. The West Texas cost data for reworking wells provides the foundation for the New Mexico cost equation.

Figure C-5. Cost of an Existing Waterflood Production or Injection Well for CO<sub>2</sub>-EOR in West Texas vs. Depth



6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and New Mexico primary oil production O&M costs (Figure C-6) are used to estimate New Mexico secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table C-1.

Figure C-6. Annual Lease O&M Costs for Primary Oil Production by Area

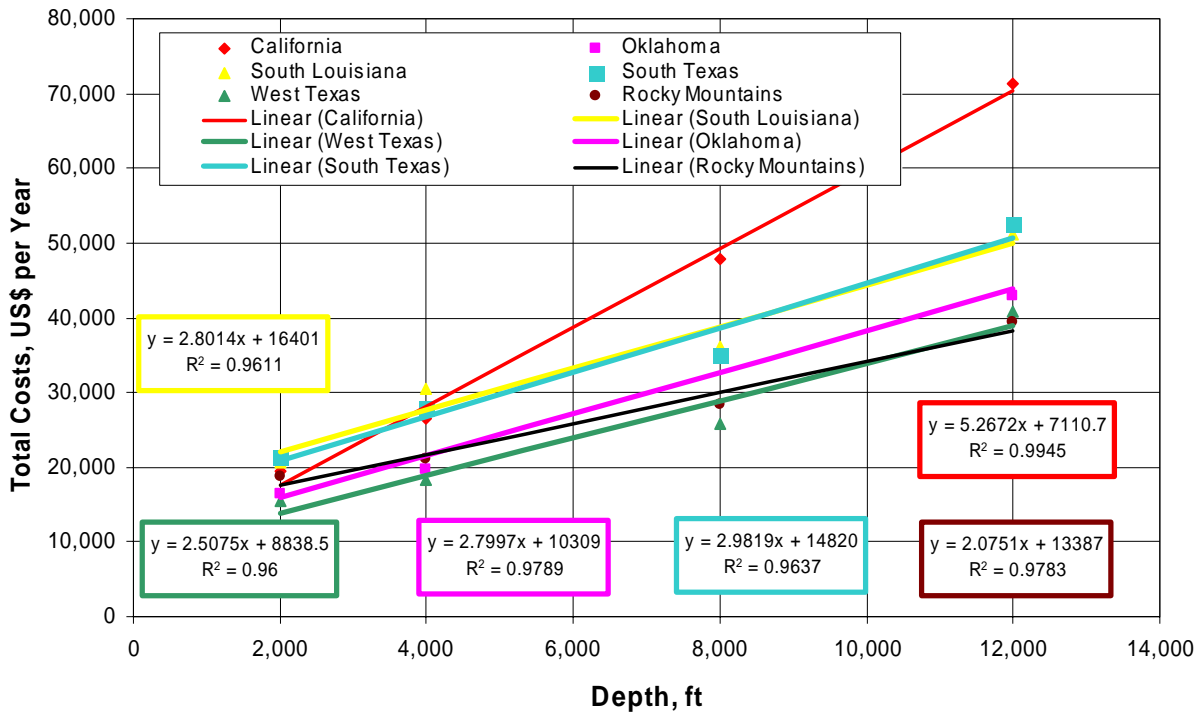


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

Basin	C <sub>0</sub>		Ratio to W. TX	
	US\$	US\$	C <sub>0</sub>	C <sub>1</sub>
New Mexico	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

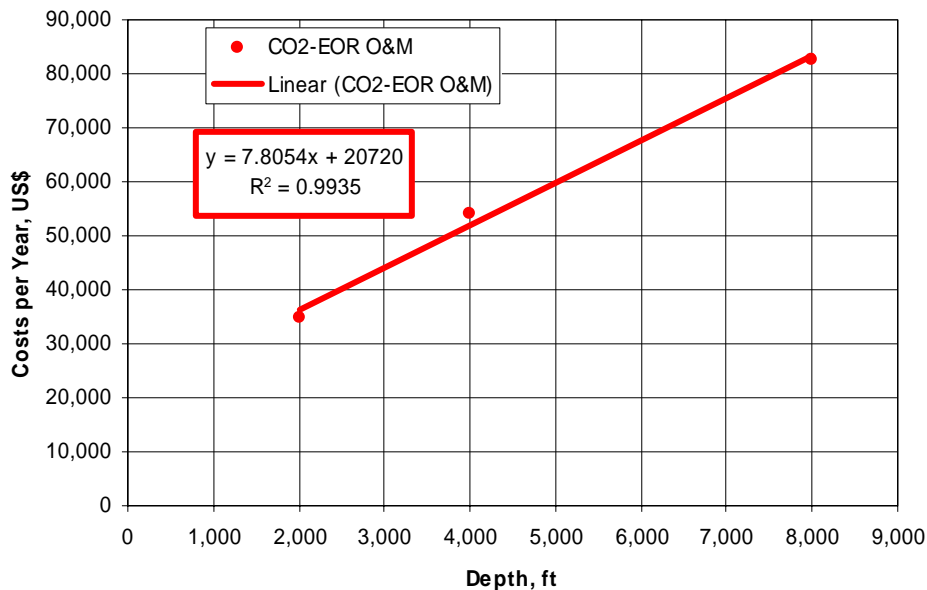
To account for the O&M cost differences between waterflooding and CO<sub>2</sub>-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO<sub>2</sub>-EOR projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO<sub>2</sub>-EOR. (Liquid lifting costs for CO<sub>2</sub>-EOR are discussed in a later section of this appendix.)

Figure C-7 shows the depth-relationship for CO<sub>2</sub>-EOR O&M costs in West Texas. These costs were used for O&M for New Mexico, shown in the inset of Figure C-7. The equation for New Mexico is:

$$\text{Well O\&M Costs} = b_0 + b_1D$$

Where:  $b_0 = \$20,720$  (fixed)  
 $b_1 = \$7.805$  per foot  
 $D$  is well depth

Figure C-7. Annual CO<sub>2</sub>-EOR O&M Costs for West Texas



7. CO<sub>2</sub> Recycle Plant Investment Cost. Operation of CO<sub>2</sub>-EOR requires a recycling plant to capture and reinject the produced CO<sub>2</sub>. The size of the recycle plant is based on peak CO<sub>2</sub> production and recycling requirements.

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO<sub>2</sub> capacity. As such, a small CO<sub>2</sub>-EOR project in the Delaware Sand formation of the Paduca field, with 24 MMcf/d of CO<sub>2</sub> reinjection, will require a recycling plant costing \$17 million. A large project in the Empire field, with 229 MMcf/d of peak CO<sub>2</sub> reinjection and 84 injectors requires a recycling plant costing \$160 million.

The model has three options for installing a CO<sub>2</sub> recycling plant. The default setting costs the entire plant one year prior to CO<sub>2</sub> breakthrough. The second option places the full CO<sub>2</sub> recycle plant cost at the beginning of the project (Year 0). The third option installs the CO<sub>2</sub> recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO<sub>2</sub> breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

## 8. Other COTWO Model Costs.

a. CO<sub>2</sub> Recycle O&M Costs. The O&M costs of CO<sub>2</sub> recycling are indexed to energy costs and set at 1% of the oil price (\$0.25 per Mcf @ \$25 Bbl oil).

b. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and costed at \$0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. CO<sub>2</sub> Distribution Costs. The CO<sub>2</sub> distribution system is similar to the gathering systems used for natural gas. A distribution “hub” is constructed with smaller pipelines delivering purchased CO<sub>2</sub> to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is \$150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO<sub>2</sub> injection requirements. These range from \$80,000 per mile for 4” pipe (CO<sub>2</sub> rate less than 15MMcf/d), \$120,000 per mile for 6” pipe (CO<sub>2</sub> rate of 15 to 35 MMcf/d), \$160,000 per mile for 8” pipe (CO<sub>2</sub> rate of 35 to 60 MMcf/d), and \$200,000 per mile for pipe greater than 8” diameter (CO<sub>2</sub> rate greater than 60 MMcf/d). Aside from the injection volume, costs also depend on the distance from the CO<sub>2</sub> “hub” (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO<sub>2</sub> distribution cost equation for New Mexico is:

$$\text{Pipeline Construction Costs} = \$150,000 + C_D * \text{Distance}$$

Where: C<sub>D</sub> is the cost per mile of the necessary pipe diameter (from the CO<sub>2</sub> injection rate)

Distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. Royalties. Royalty payments are assumed to be 12.5%.

f. Production Taxes. New Mexico has enacted risk sharing actions for enhanced oil recovery. The New Mexico Tax Code section 7-29-4.1 provides incentives for production tax rate reductions for various projects in New Mexico including qualified enhanced oil recovery projects.

The state normally charges a 3.75% severance tax on all oil production; however the rate is dropped by 50% to 1.875% for qualified EOR projects. This savings of 1.875% equates to 49 cents per barrel of oil produced. The ad valorem tax rate varies by county and an average value of 2.318% was used. In the model, severance and ad valorem taxes are charged after royalties are taken out.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis (\$0.00 differential for New Mexico) and the current gravity differential (-\$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for New Mexico is:

$$\text{Wellhead Oil Price} = \text{Oil Price} + (-\$0.60) - [\$0.25*(40 - \text{°API})]$$

Where: Oil Price is the marker oil price (West Texas intermediate)

°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within New Mexico contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 °API for all fields with lighter oil when applying the Crude Oil Price Differential.